

Smart Power Grid – Alternative Technologies Workgroup 21st Century Energy Plan

1. Introduction and Methodology

1.1 Introduction

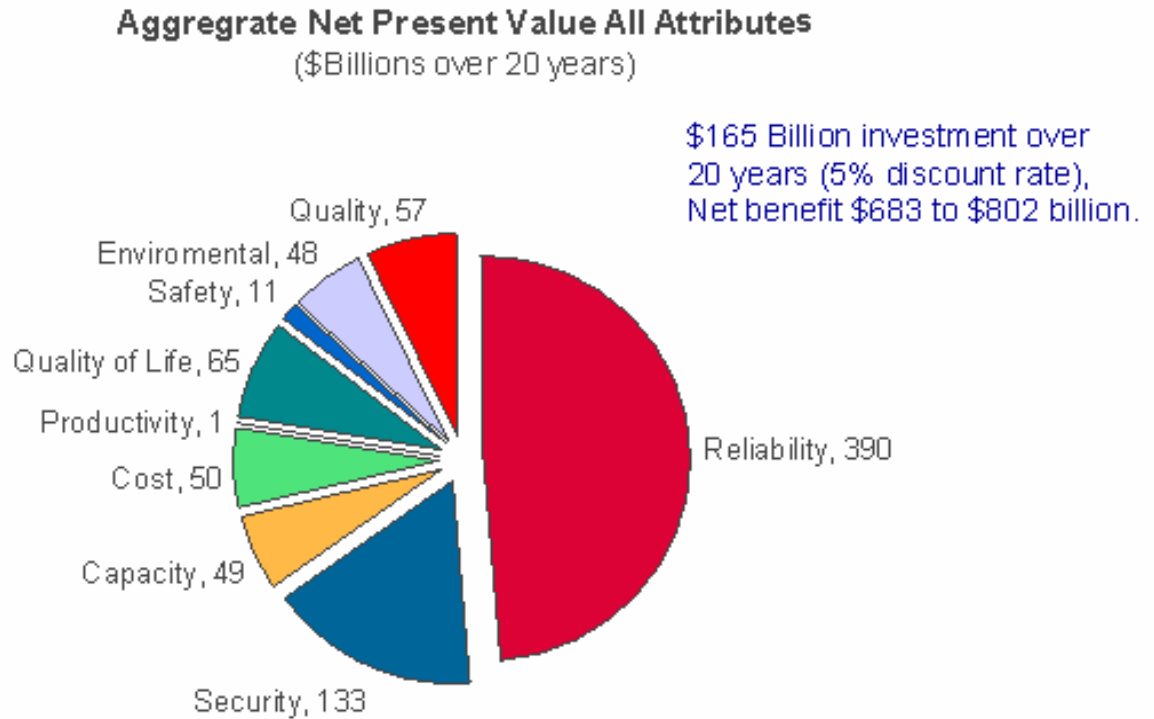
Market forces, technology advances, national energy policy and regulation are transforming the various components of the nation's electric infrastructure and the manner in which the power grid is operated. For example, new regional markets are developing along with wholesale competition, and additional operational issues are surfacing along with the deployment of distributed generation resources and other new technologies. These changes have drawn attention to the opportunities for improved grid reliability, increased market efficiencies, and enhanced customer value, which these technologies can help realize.

Changes induced by new technologies are gradually beginning to transform the historical power grid system, which has been operated by electro-mechanical controls. The "Smart Power Grid" (SPG) is a general concept for this process of transforming the nation's electric power grid by applying computers, electronics, and advanced materials to implement communications, automated controls, and other forms of information technology to improve the economics, reliability and safety of the grid. This vision of a smart power grid integrates energy infrastructure, processes, devices, information, and markets into a coordinated and collaborative process which will allow electricity to be generated, distributed, and consumed more effectively and efficiently.

Eventually, implementation of smart power grid architecture will enable devices at all levels within the grid (from power generator to customer) to independently sense, anticipate and respond to real-time conditions by accessing, sharing and acting on real-time information. While the grid is gradually being transformed to provide these features, the challenge for all stakeholders is to maintain the reliability, security, and affordability of our power supply. The Figure 1 shows an estimate of the aggregate net present value of all smart power grid attributes, with the value of reliability and security accounting for 65 percent of the total value.

Figure 1: Smart Power Grid Estimated Value⁸²

Value of Reliability and Security are Highest at 65 percent of Total



Planning, managing, and operating the electric power system in a coordinated and collaborative way can provide many benefits for both customers and power system providers. As new technologies become available, they can be integrated into the system when they can be shown to provide clear benefits. Smart power grid technologies continue to evolve and are in many different stages of development and commercialization. Incremental deployments of the new technologies will happen as their cost effectiveness is demonstrated and industry standards emerge. Many stakeholder groups are currently involved in the process of organizing, studying, specifying, designing, testing and implementing the hardware and concepts of a Smart Power Grid through a variety of study groups, alliances, collaborative, and pilot projects.

Additional information on technology options, barriers to adoption, commercial readiness, and applications related to smart power grid architecture and communications is presented later in this report, in Table 1 (p. 215)

⁸² Source: *Power Delivery Systems of the Future: A Preliminary Estimate of Costs and Benefits*, EPRI, Palo Alto, CA: 2004; <http://www.epri.com>.

The Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability has identified seven principal characteristics of a smart electric grid.⁸³ These characteristics are:

1. Self-Healing: A grid able to rapidly detect, analyze, respond, and restore from perturbations.
2. Empower and Incorporate the Consumer: A grid able to incorporate consumer equipment and behavior.
3. Tolerant of a Security Attack: A grid that mitigates and stands resilient to physical and cyber security attack.
4. Provides Power Quality Needed by 21st Century Users: A grid that provides a quality of power consistent with consumer and industry needs.
5. Accommodates a Wide Variety of Generation Options: A grid that allows and takes advantage of a wide variety of local and regional generation technologies (including green power).
6. Fully Enables Electricity Markets: A grid that fully enables maturing electricity markets.
7. Optimizes Asset Utilization: A grid that employs IT and monitoring technologies to continually optimize its capital assets while minimizing operations and maintenance costs (O&M) costs.

1.2 Methodology

Workgroup participants identified four functional categories for smart grid technologies. These categories are:

1. architecture and communication standards;
2. monitoring and load management;
3. advanced grid operations; and
4. modeling and simulation.

These categories are intended to embrace the entire power system from points of energy production to points of energy use and the safe, reliable and efficient integration of both supply and demand.

The Smart Power Grid concept envisions even greater levels of functional integration with the application of increasingly sophisticated technologies for monitoring, operations, and control of the grid. The connection of many smaller generation sources and the requirements of higher power quality standards to power digital technologies are driving the need for new and more sophisticated grid operating technologies. Maintaining and improving historical levels of reliability, safety and economic efficiency will require an increased level of attention if the advancement of Smart Power Grid concepts is to make steady progress.

⁸³For more information, refer to the discussion beginning in Section 3.3 of this document and the following website: <https://www.themoderngrid.org>.

2. Smart Power Grid Architecture, Monitoring and Operations

2.1 Architecture and Communication Standards

Deployment of Smart Power Grid technologies will require increased emphasis on architecture and communications standards, which accommodate the many new operational requirements brought on by a transitioning electric power industry. Traditional levels of affordability, reliability, security and resilience must be supported and enhanced as the grid experiences new challenges. Some of these challenges include jurisdictional issues, increased power transactions between new market participants, increased need for new construction to relieve congestion, increased need for higher levels of power quality, greater need for grid security and the demand for more customer options.

The Smart Power Grid will require a new architecture which defines participants, grid functions and a systems approach to the interdependence of all of the grid's components. In this context, architecture describes the overall technical framework for development, installation, operation and maintenance of an information system. The Smart Power Grid is comprehensive reference architecture for the entire energy delivery infrastructure. Components of the architecture include the following:

1. develop approach for integrating legacy systems into a smart electricity infrastructure information system;
2. expand North American Electric Reliability Corporation (NERC) Electric Reliability Organization (ERO) approach to standard development;
3. construct an interoperability classification system;
4. define standards to satisfy operational requirements for domains within operational classification system; and
5. create the necessary security assessment tools.

The important challenges for identifying, scoping, specifying and implementing the Smart Power Grid architecture and standards requirements will include incorporation of large numbers of legacy systems for full functioning without degrading performance and reliability. In addition, many disparate industry and standards activities must be coordinated and compatible with operational technologies and capable of responding to day-to-day and emergency situations.

2.2 Monitoring and Load Management

The challenge for monitoring and load management technologies is to enhance monitoring of grid operations for power quality and power flow disturbance location, prediction and prevention. Also, improved monitoring and load management technologies should be employed to manage control of industrial, commercial and residential loads as part of demand side management (DSM) programs.

For purposes of grid monitoring and control, most electric utilities employ a Supervisory Control and Data Acquisition (SCADA) computer. The SCADA system is a communication tool enabling real-time measurements to be sent from substations to a System Control Center and

control signals to be sent from the System Control Center to the substations. This system allows operators to monitor power flow through and voltage at high voltage substations and electric lines. It also allows operators to control certain electric facilities like circuit breakers by opening or closing circuit breakers remotely from the System Control Center.

Many SCADA systems have complementary or supplemental computer software packages for use by grid operators. This software allows grid operators to anticipate operational situations such as an increase in electric demand or the failure of a high voltage electric facility like a line or transformer. These supplemental computer software programs are often called advanced applications. One such application is termed “State Estimation.” This software can use the real time SCADA information to predict power flow and voltage at certain locations on the power grid even though no telemetry information is available from the field. Another application is an on-line power flow. For example, using real time (on-line) SCADA information, operators and engineers can run simulations of hypothetical situations to better understand what operating issues may occur and devise a plan to manage an undesirable power flow situations.

Challenges for the future of monitoring and load management technologies include:

1. increased use of next-generation sensors on transmission and distribution equipment for accurate voltage, current and temperature measurements;
2. increased integration of grid system monitoring (SCADA) with customer usage monitoring (AMI) for purposes of improved power flow, power quality and diagnostics as well as enhanced customer service; and
3. increased development and use of smart appliance technologies.

For additional information on technology options, barriers to adoption, commercial readiness, and grid applications related to monitoring and control, see Table 1.

2.3 Grid Operations

Grid operations employ increasingly sophisticated components to balance power supply and demand. While distributed generation has not yet reached significant penetration levels in the U.S., the situation is changing rapidly, with national attention focused on alternatives to building traditional central station plants. Increasing the penetration levels for distributed generation will require specific attention to operational details required to maintain the transmission grid’s integrity. This approach views individual distributed generators and their associated loads as a subsystem or “microgrid.” The microgrid concept employs some of the following techniques:

1. increased efficiencies by matching generators and loads using waste heat sources;
2. intentional “islanding” during grid disturbances for improved reliability; and
3. sophisticated generator-based controls capable of smart-disconnect and resynchronization, thus avoiding complex customized control system engineering for each application.

Power quality improvement devices (i.e., uninterruptible power supplies, harmonic filters, and a combination of capacitors and inductors installed on customer equipment) are available on the market to help customers “ride through” customer and utility electric system disturbances. For example, Bay City Power Train, a General Motors manufacturing complex in Bay City, Michigan, has installed a Dynamic Voltage Restorer to help the plant operate through voltage sags or disturbances that may occur on the electric service to the plant.

Relay technology has dramatically changed in recent years to the digital age. As a result, much more detailed electric system monitoring information is now available via digital relays that are increasingly being installed throughout utility electric systems. As a result, fault locations (the location where a problem on the electric system has occurred – like a tree falling into a line) can be successfully determined by operators and engineers to aid in the deployment of field personnel to a location very close to the problem area. Without the ability to determine the location of the fault (or short circuit) on a line, field personnel have to inspect the line (sometimes walking it from one end to the other) to find the problem.

Communications technology has been improving and costs are declining. As a result, more options on economic terms are now available to automatically sectionalize distribution circuits. Consumers Energy has deployed S&C Electric’s IntelliTeam switches and controls at a few locations on its low voltage distribution system. Such equipment will automatically reconfigure the low voltage distribution system during a failure and restore customers to service on parts of the distribution circuit not directly affected by the equipment failure.

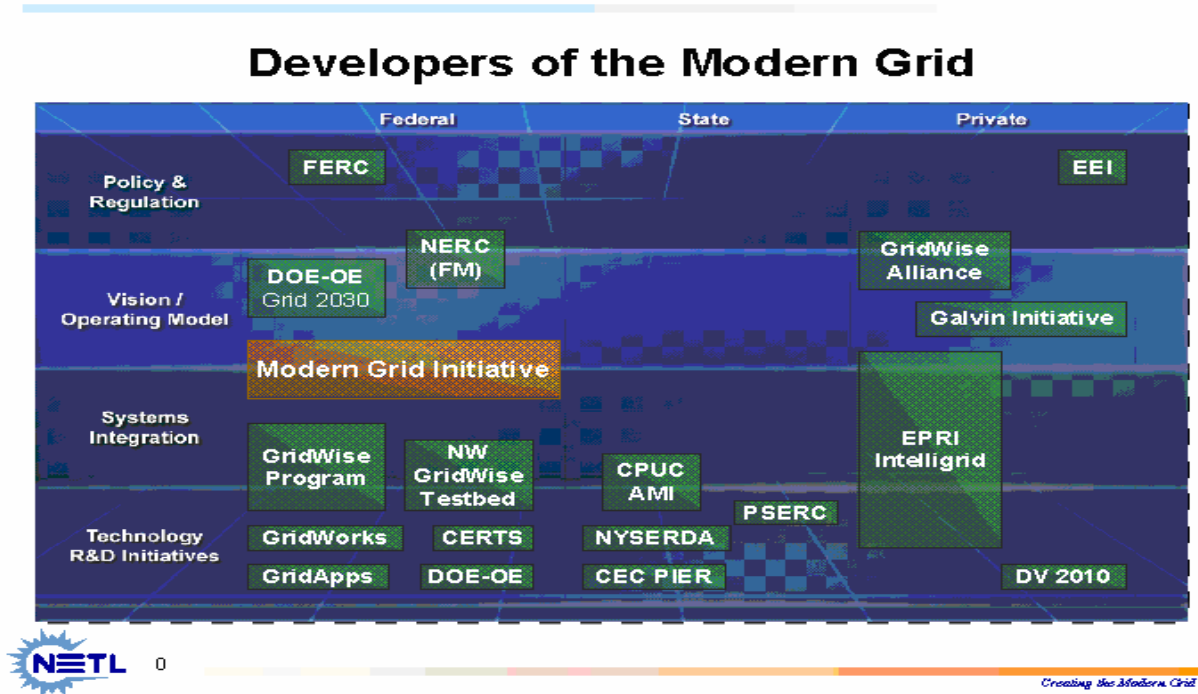
For additional information on technology options, barriers to adoption, commercial readiness, and grid applications related to advanced grid operations, see Table 1.

3. National Smart Power Grid Initiatives

There are several initiatives underway to explore the opportunities, performance, and operational issues of “smart grid” technology. Stakeholders involved in initiatives to transition the electric power grid infrastructure include approximately 3,000 electric utilities nationwide, their representative organizations, various trade and professional organizations that represent their employees, the Department of Energy, the Federal Energy Regulatory Commission (FERC), Congress, and the state public utility commissions, consumer protection and interest groups, and electricity consumers. Figure 2, provided by the National Energy Technology Laboratory (NETL)⁸⁴ depicts the development of the modern grid.

⁸⁴ NETL is part of DOE’s national laboratory system and is owned and operated by the US Department of Energy. NETL is managing The Modern Grid Initiative that is discussed in more detail in Section 3.3 of this document. For more information on NETL, see link: <http://www.netl.doe.gov/>.

Figure 2: Developers of the Modern Grid - NETL



The nation-wide activities which complement federal energy policy can be loosely grouped as follows:

1. U.S. Department of Energy activities (GridWorks/Gridwise; Modern Grid Initiative; etc.);
2. university consortium activities (PSERC);
3. industry supported projects (EPRI's IntelliGrid Consortium);
4. privately-funded activities (Galvin Initiative); and
5. state programs.

A description of each initiative is included below.

3.1 IntelliGrid⁸⁵ (EPRI)

The IntelliGrid Consortium was created by the Electric Power Research Institute (EPRI) to help the industry pave the way to the IntelliGrid vision of the power grid of the future. Such an evolution means avoiding easy short-term solutions that lead to a "silo" approach - one without regard to the needs of other parts of the grid. It stresses the advantage and need for open

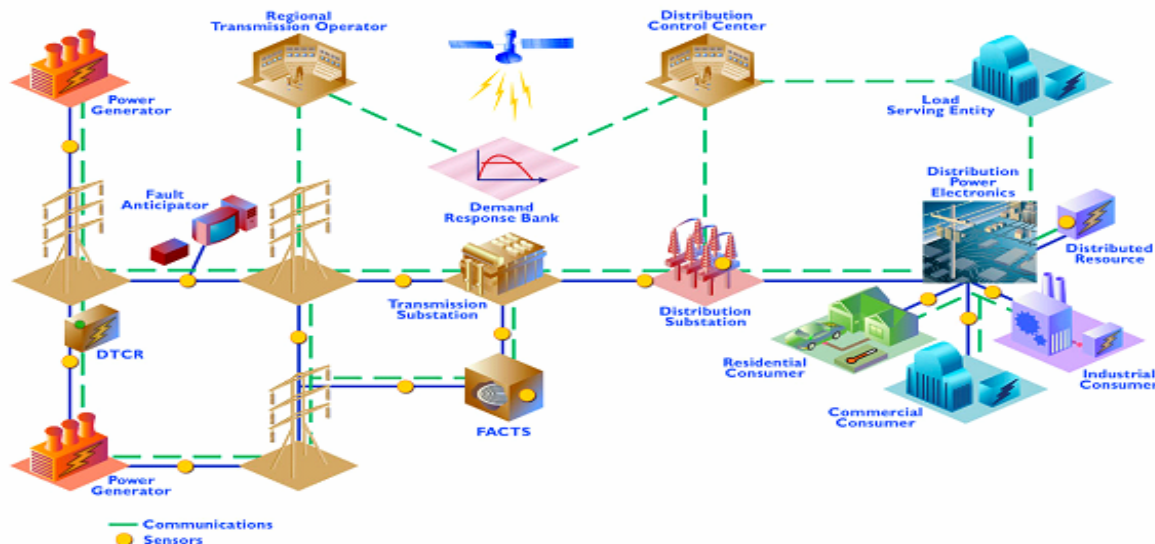
⁸⁵Source: Abstracted from the EPRI IntelliGrid website with permission of EPRI see: <http://www.epri.com/IntelliGrid/> for further information.

standards, coordination of research and development (R&D), collaboration among all stakeholders and a leadership role in the industry standards boards and regulatory bodies. The process is the key to the success of IntelliGrid. Success requires adoption by the industry. Figure 3 illustrates the IntelliGrid vision.

The IntelliGrid Consortium is a public/private partnership that integrates and optimizes global research efforts, funds high-impact R&D on enabling technologies and on the integration of technologies to achieve the vision of the power delivery system of the future. The IntelliGrid Consortium also leads an international effort to disseminate technical conclusions for the benefit of the public by promoting its adoption by others (standard groups, trade associations, etc.).

Figure 3: EPRI Intelligent Grid Communications

The Intelligent Grid Uses Smart Devices, Communications, and Computing



The IntelliGrid Architecture is a world-wide and industry-wide project to develop the infrastructures necessary to support the next generation of energy conversion, delivery and end-use systems. The IntelliGrid Architecture builds upon work within several developing and emerging open standards to enable not only interoperable equipment but provide a framework for the development of the next generation of automation applications. The Architecture focuses on the effective integration of two infrastructures:

- electric energy and power delivery system; and
- communications and intelligent equipment that will be used to control and manage energy and power systems in the future.

The IntelliGrid Architecture development began with an initial project known as the Integrated Energy and Communications System Architecture (IECSA). This project provided an initial set

of requirements that represent "architecturally significant" applications, analyses and guidelines to help direct the industry toward the development of advanced automation systems that can be integrated on large scales.

The IntelliGrid Architecture is focused on the effective use of advanced automation products that can be integrated through the use of open standards, many of which are now or have reached maturity. Architecture development is necessary to manage the complexity of future applications and technologies, and to assist the development of advanced devices and systems that are interoperable.

The scope of IntelliGrid Architecture is as large as the existing energy conversion, delivery and end-use technologies. This broad scope is necessary to encompass the levels of integration that by definition constitute industry-level architecture. For context with existing power system taxonomy, the team initially categorized the work by traditional technical domains as follows:

- central power generation;
- transmission operations;
- market operations;
- distribution operations;
- distributed energy resources;
- consumer communications; and
- federated and system management services.

Other major IntelliGrid project areas include the following:

3.1.1 Fast Simulation and Modeling

Fast Simulation and Modeling intended to help the operators to have a clear and accurate estimation of the grid, to cost efficiently optimize the operations, and anticipate responses to events in real time, achieve faster-than-real time simulation and modeling of electricity grid dynamics over a range of different geographic and time domains.

3.1.2 The Consumer Portal

The Consumer Portal intended to enable consumers to participate in the competitive energy markets, and provide action and feedback from the consumers, who represent millions of connecting points to the network. It not only provides an interface for energy related services (e.g., meter reading, outage detection, demand response, bill disaggregation, and real-time pricing), but also numerous additional potential functions to industrial, commercial, and residential electric energy users.

Communication Standards for Distributed Energy Resource (DER) Integration and for Advanced Distributed Automation (ADA) – Changes to the distribution electrical system and communication system are needed in order to fully capture the prospective benefits of new distribution technologies. Individual equipment types, such as DER, must be made interoperable

with overall infrastructure. This project addresses communication standards aimed at helping to achieve this interoperability.

3.2 GridWorks/GridWise⁸⁶ (DOE)

There are two U.S. Department of Energy directed research and development programs (GridWorks and GridWise) to improve the reliability of the electric infrastructure through research and development of key grid systems and components.

The GridWorks program addresses introduction of “next generation” grid hardware. Participants include electric utilities, equipment manufacturers, state government agencies, National Laboratories and universities. The GridWorks effort began in October 2004 and has been conducted on a workshop format. The workshop effort was designed to encourage partnerships and collaboration to achieve implementation of advanced grid hardware in three major areas. These areas are: (1) cables and conductors; (2) power electronics; and (3) substation and protective equipment. The workshops concluded with production of a GridWorks Multi-Year Plan in March 2005.

The GridWise program addresses increased integration of information systems and digital technologies into the electric grid. The future electric system is expected to employ new distributed “plug and play” technologies using advanced telecommunications, information and control approaches to create a society of devices that functions as an integrated transactive system.

The GridWise Alliance is a consortium of public and private stakeholders who have joined together in a collaborative effort to provide practical technology solutions to support the U.S. Department of Energy's vision of a transformed national electric system.

3.3 Modern Grid Initiative⁸⁷ from DOE

The Modern Grid Initiative (MGI) was commenced in April of 2005, when the DOE Office of Electricity Delivery and Energy Reliability asked the National Energy Technology Laboratory to create the Modern Grid Initiative to advance a national effort involving a partnership among utilities, consumers, national labs, academia, industry firms, regulators and policy makers to improve the national grid in a way to support the 21st century U.S. economy. The MGI is intended to empower researchers and other stakeholders to connect, collaborate and move forward in partnership through summits, working groups, and developmental field tests.

MGI has started the process of hosting a series of regional summits in the U.S. in order to engage a broad range of stakeholders in creating a shared national agenda for modernizing the electrical grid. To date, MGI has hosted a Southwest Regional Summit in Arizona (November 2005 with 60 attendees), a Northwest Regional Summit in Oregon (April 2006 with 80 attendees), a Northeast Regional Summit in Maine (June 2006), and a Southeast Regional Summit in

⁸⁶ For more information, about DOE GridWise, see web link at: <http://gridwise.pnl.gov/>. For more information about DOE GridWorks, see web link at: <http://www.oe.energy.gov/randd/gridworks.htm>.

⁸⁷ For more information about the Modern Grid Initiative, see web link at <http://www.themoderngrid.org/>.

Tennessee (August 2006), a San Diego Summit (October 2006), and a Midwest Regional Summit in Ohio (November 2006). Upon completion of the Regional Summits, MGI plans to host a National Summit in order to share the information gained from the Regional Summits, and obtain feedback from a large audience of stakeholders. In addition to the summits, MGI established a working group in July 2006 in order to improve the quality of MGI concepts, create consensus for MGI concepts, increase the credibility of MGI concepts, and provide stakeholders another opportunity to participate.

In April 2006, MGI reached an agreement in principal with American Electric Power (AEP) for a developmental field test of advanced grid technologies in West Virginia, delivering some of the principal characteristics of the Modern Grid. In May 2006, MGI reached an agreement in principal with Allegheny Power for a similar developmental field test in West Virginia.

MGI's goals for fiscal year 2007 include the full operation of two to three developmental field tests, and continued stakeholder alignment. The goals for fiscal years 2008 through 2012 include the bid, selection and deployment of large regional demonstration projects, as well as the refinement of the Modern Grid strategies through lessons from the demonstrations. MGI expects that the adoption of the Modern Grid strategies by appropriate national and state organizations will take place in 2013, which will be the basis for national deployment.

3.4 GridApp™⁸⁸

GridApp™ (Advanced Grid Applications Consortium), a partnership of electrical utilities and the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability. The mission of GridApp™ is to transition best technologies and best practices to support grid modernization into broad use by consortium member utilities.

This multi-company consortium focuses on High-Impact Technologies for electricity distribution and transmission, including: sensors, communications, information technologies, power electronics, smart systems, and system integration. GridApp™ provides a fast track for engineering development, demonstration, verification, and validation of selected, High-Impact Technologies and practices. GridApp™ also provides informational briefings and technology showcases to promote use by all member utilities. GridApp™ is designed in a flexible way to allow for rapid deployment of innovations and activities that focus on development of technologies with a high potential for near-term application and commercialization. GridApp™ provides member utilities with technical and financial resources to develop and deploy grid modernization technologies that they would be unable to develop and deploy on their own. Participants in GridApp™ benefit from:

1. pooling resources to fund best technologies/practices;
2. bringing commercially available technologies into real use;
3. lowering market entry barriers for new technologies;
4. gaining advance knowledge of and preferred pricing on GridApp™ technologies in Core and Strategic projects;

⁸⁸ For more information about GridApp™, see web link at https://www.gridapp.org/eidb/gridapp_home.htm.

5. partaking in a forum to communicate and share technology advancements;
6. becoming an effective change agent of new technologies important to the utility industry; and
7. forging a collective voice of the utility industry for advocacy of technology investments.

Coordinating collaborative approaches with federal/state programs to support high-priority projects, the GridApp™ mission is dedicated to transitioning utility “best practices and technologies” into broad use by GridApp™ Consortium member utilities. The GridApp™ focus is on high-impact technologies for distribution and transmission operations, including but not limited to; sensors, controls, communications, power electronics, smart systems and system integration.

GridApp™ intends to fast-track the engineering development, demonstration, verification, validation and deployment of such high-impact technologies and practices with beta-testing completed in less than 18 months. In addition GridApp™ provides a venue for informational briefings, technology showcase and networking opportunities for participating Consortium members.

3.5 Galvin Electricity Initiative⁸⁹

On September 22, 2005, the Galvin Electricity Initiative officially announced its mission to create a blueprint for transforming the U.S. electricity supply and service infrastructure into a resilient and adaptable system supporting the needs of the rapidly evolving digital economy. The fundamental principle of this Initiative is that raising the quality of the nation's electricity supply system will create substantial cost savings for all consumers and society at large.

The Initiative is a privately funded enterprise sponsored by the Galvin Project, Inc., which is led by Bob Galvin, former CEO of Motorola and a key figure in establishing the internationally recognized “Six Sigma” quality control process. According to EPRI President Emeritus Kurt Yeager, who is leading the Galvin Electricity Initiative, “The electric infrastructure has to be transformed. It was adequate for the analog, electromechanical world of the 20th century, but needs to be reinvented to meet the demands of the '24-7' electronic age.”

The Galvin Project consists of two phases and is being conducted by researchers from EPRI, under the leadership of Clark W. Gellings, Vice President of Innovation, with support from EPRI Solutions, Inc., Strategic Decisions Group, and the University of Minnesota. The goal of the, recently completed, first phase was to determine the principal innovations which will play a major role in adapting to and shaping customers' electric energy service needs in the next 10 to 20 years.

⁸⁹ For more information, see web link at <http://www.galvinelectricity.org/>.

3.6 MultiSpeak® Initiative (NRECA)⁹⁰

The MultiSpeak® Initiative is a collaborative effort of the National Rural Electric Cooperative Association (NRECA) and more than 30 software providers and consultants serving electric utilities. The MultiSpeak® collaborative effort began around October 1999 and offers independent specifications that are used by software developers to simplify business process improvement and data integration at electric utilities, with particular emphasis on electric distribution cooperatives. The MultiSpeak® specification defines what data is exchanged among commonly used software applications, and establishes standardized messaging formats. Software providers use the specification to write interfaces that will enable the interchange of information with other software that supports MultiSpeak®.

MultiSpeak®3, the latest release of the specification, supports batch file transfers and real-time transport using web services, which standardize the transport of instructions and data among MultiSpeak®-compatible software applications. MultiSpeak®3 defines more than 200 unique web service methods to implement real-time data and process integration. In addition to automated meter reading and engineering analysis, software applications covered in the latest specification include customer information systems, outage detection, outage management systems, field design software, geographic information systems, customer relationship management, load management, and SCADA.

3.7 Consortium for Electric Reliability Technology Solutions⁹¹

The Consortium for Electric Reliability Technology Solutions (CERTS) is an organization formed in 1999 to research, develop, and disseminate new methods, tools, and technologies to support electric power system reliability and the functioning of competitive electricity markets in the United States. CERTS includes participants from universities, national laboratories and private industry. CERTS are currently conducting research for the U.S. Department of Energy Transmission Reliability Program and for the California Energy Commission (CEC) Public Interest Energy Research (PIER) Program. The members of CERTS include the Electric Power Group, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, the National Science Foundation's Power Systems Engineering Research Center, and Sandia National Laboratories.

The CERTS Microgrid concept, a major focus of the consortium, employs distributed energy resources (DER) to improve grid reliability and efficiency. A high-speed switch with appropriate sensing capability is used to isolate the microgrid from the power system during abnormal grid conditions. This approach improves local power quality and diminishes the chances of a local disturbance propagating a wider grid disruption.

⁹⁰ For more information, see web link at <http://www.multispeak.org/>.

⁹¹ For more information, see web link at <http://certs.lbl.gov/>.

3.8 Distribution Vision 2010 Consortium

The Distribution Vision 2010 Limited Liability Company was formed July 2002, with five registered owners: Wisconsin Energy Corp., Alliant Energy, AEP, PSE&G, and OG&E. BC Hydro is a non-owning member of the consortium. DV2010 was organized to develop ideas for new technologies for the power distribution industry. The goal of the consortium is to improve the reliability of customer service. The approach is to develop conceptual ideas for new technologies and fund the engineering feasibility studies necessary for commercialization of those ideas. It seeks out industrial suppliers with the best potential for bringing the best ideas to market.

4. Michigan Grid Modernization Technologies

4.1 Introduction

The Michigan electric industry has already made significant investments in communication and information handling infrastructure and the associated equipment and components.

For example, most modern control areas use a Supervisory Control and Data Acquisition (SCADA) system for real time information and control. SCADA systems can also be used to more efficiently and more optimally operate electric devices on the system, like switchable capacitor banks. Consumers Energy has implemented a program which allow certain capacitor banks located on low voltage distribution circuit feeders to be switched on and off by the reactive power flow on the high voltage electric line feeding the low voltage distribution line. This in turn results in reduced use of devices like voltage regulators (allowing decreased equipment wear and tear and lower maintenance costs) and achieves a flatter voltage profile on distribution circuits. It also reduces electric system losses and enhances the availability of reactive power.

As another example, some utilities employ power quality recording devices at large customer locations to monitor service at the power of interconnection between a customer and utility. These devices help identify power disruption events on the utility system or the customer's system when the customer experiences a disruption, and they can also help predict the imminent failure or poor operation of an electrical device before failure of the device occurs.

A number of Michigan cooperative electric distribution companies have already initiated programs to replace utility meters that required manual meter reads with new ones that allow automatic meter reading. Such technologies permit two-way communications between the customer meter and the distribution company's control center. Not only can meters be read remotely, outage assessments can likewise be performed without dispatching crews or awaiting calls from customers reporting outages. Detroit Edison (DTE) has experimented with meter communications over both its distribution system and via fiber-optic cable.

State policy has also pushed the need for grid modernization. The Commission has adopted interconnection standards for units interconnecting to the distribution system in Michigan. These standards are intended to provide uniform requirements for distributed energy resources that seek

to interconnect to Michigan's power grid. The Commission has also adopted a net metering program for small, renewable applications. Under this program, units that produce less than 30 kilowatts (kW) from a renewable power source can produce electricity for domestic use and receive credit for any excess generation delivered to the power grid.

4.2 Grid Modernization Recommendations

If grid modernization is approached in a thoughtful manner, Michigan can become the center for electricity innovation, which will attract investment, and encourage successful businesses to locate here. Advancing the concept of the Smart Power Grid will provide a more reliable and secure power supply, provide other directed economic benefits, and stimulate technological innovation and bring about a more vibrant economy and a better quality of life for Michigan residents.

4.3 Collaborative Concept for Michigan

A collaboration-focused approach allows participants an opportunity to achieve mutual success by leveraging technology and innovative ideas to advance the concept of a Smart Power Grid. The many successful national collaborative efforts investigating advanced grid technologies will provide guidance to similar efforts for Michigan.

4.4 Pilot Project Concept for Utility(s)

A number of pilot projects are underway around the country. A federal energy policy push is encouraging media coverage as well as deployment of pilot programs to advance Smart Power Grid technologies. Consumers Energy currently has a pilot program for Broadband over Powerline (BPL) underway in Michigan. There a number of BPL deployments around the country. Several have gone beyond the pilot stage. Other Smart Power Grid and related applications are also being deployed in pilot projects. Examples include smart appliances, smart metering, power outage monitoring, monitoring of grid component failures and others.

The Energy Policy Act of 2005 (EPACT 2005) directs the FERC to encourage the deployment of advanced transmission technologies and authorizes the Secretary of Energy to establish an Advanced Power System Technology Incentive Program to deploy certain advanced power system technologies. Also, EPACT 2005 amends the Public Utility Regulatory Policies Act of 1978 (PURPA) by encouraging each state regulatory authority to investigate the use of time-based meters and communication devices. The current legislative environment should stimulate interest in beginning pilots in these technology areas.

4.5 Detroit Edison Modernization Activities

The following DTE initiatives support smart power grid technical categories and involve both full scale and pilot deployments.

4.5.1 Aggregation, Communication and Control of Distributed Energy Resources

As the project leader of a Department of Energy funded demonstration project, DTE created the communication and system architecture, and the procedures to monitor and control multiple DERs from numerous manufacturers connected to the electric distribution system. Procedures were created which protect the distribution network and personnel that may be working on the network. Using the web as the communication medium for control and monitoring of the DERs, the integration of information and security was accomplished through the use of industry standard protocols such as SSL (secure sockets layer) and ICCP (Inter control center protocol).

In Phase II of the project (completed in 2006), marketing procedures were developed for marketing the power of the aggregated DERs by commercial node in the Midwest Independent System Operator (MISO) energy market. DTE demonstrated the economic dispatch of 32 generators at 24 different sites, totaling 18 megawatts (MW) in response to market signals without human intervention. The selection of standards-based communication technologies offers the ability of the system to be deployed and integrated with other utilities' resources.

4.5.2 SCADA/EMS Replacement

DTE's existing SCADA and Energy Management System is being replaced due to obsolescence, the new system will enable DTE to meet the NERC Critical Infrastructure Protection (CIP) Standards. The applications included in the replacement are SCADA, Historian for data storage and retrieval, network applications such as State Estimator and Contingency Analysis that support real time analysis and operation planning, and Dispatcher Training Simulator. New tools with this replacement include real time distribution study tools, to facilitate restoration and loading of the distribution circuits.

The new system architecture will consist of an integrated Energy Management System and Distribution Management System. Some of the features include:

- sized to be able to grow the system by 50 percent and not affect performance.;
- CIM/XML Schema for model exchange;
- DNP 3.0 and DNP over IP protocols;
- ICCP and Secure ICCP for real time data exchange;
- User Interface that supports interoperability with MS Windows applications;
- web based displays for viewing;
- creation of a disaster recovery system;
- on-line study tools for System Operators to utilize to improve restoration; and
- distribution VAR control to utilize feeder capacitors efficiently.

System implementation began in the 4th quarter of 2004 and cutover is anticipated in the 3rd quarter of 2007.

4.5.3 GridApp™ Technologies

DTE is a member of GridApp™ and is the project leader for a single phase dropout recloser project that is to replace a standard utility fuse. Most faults on overhead distribution circuits are momentary outages causing fuses to blow to isolate faults resulting in customer outage until the utility replaces the fuse. A device that will operate to reduce the chance of a momentary faults becoming a permanent fault will translate into reduced momentary outages for customers, directly increasing customer satisfaction and reducing outage cost for utilities.

Another product DTE is using that was developed by a GridApp™ utility is a padmounted substation (also referred as a DC-IN-A-BOX). Because growth in existing electric infrastructure often requires new and expanded substations, a method was needed to accommodate substation siting using a less objectionable design, allowing for quicker installation, while lowering substation costs.

The Substation in a Box system offers a smaller footprint, is more aesthetically appealing while using underground cabling. The installation requires no fence topped with barbed wire for security and personal protection and no spill containment is required, thus security is enhanced. The system uses completely enclosed boxes with no exposed energized parts.

4.5.4 Automated Meter Reading

DTE has a long history of piloting new automated meter reading (AMR) technologies. As early as 1979, DTE tested AMR technology in partnership with the Electric Power Research Institute. The technology utilized at the time was a Westinghouse powerline carrier system that used existing utility lines for communication.

In 1988, a pilot involving 93 residential customer locations were automated in the Dearborn area. The meters were wired to “talk” to a central computer system over a Michigan Bell telephone line. Each meter location was retrofitted with a meter interface unit which allowed communication with up to four additional devices such as water and gas meters on the home. At the same time another pilot in the Troy area tested a system that read meters using a cable television connection. The cable system also collected meter readings from water meters at the same locations. In the late 1990s a custom technology pilot was designed in partnership with several technology vendors such as Echelon, Comcast Cable, and Hewlett Packard. This new two-way system was installed at 160 customer homes. The customers were provided an experimental time-of-use rate and the opportunity to control home appliances remotely. In 2002, a pilot of AMR fixed network technology was installed using an Itron 960 megahertz (MHz) and 1 gigahertz (GHz) meter reading system. The system was installed to cover 1,127 customer locations.

Several types of AMR technologies are currently used today at DTE. Approximately 130,000 hard to access meter locations are read via handheld radio technology. Each meter is retrofitted with a small Itron radio encoder device called an ERT module. The handheld devices used by meter readers contain a radio that picks up the meter reads when they are within a couple

hundred feet of the meter. This eliminates the need for the meter reader to walk directly up to the meter in hazardous or hard to access locations. In addition, approximately 11,000 industrial, commercial, and Load Research customer locations with interval meters are read weekly over telephone lines. A mix of both wired phone lines and analog cellular phones are used to communicate with these meters.

Many other lab tests of emerging technologies have been evaluated by DTE over the years. While many are very promising and demonstrate a reliable and accurate means of collecting data they must be cost justified as a transformation technology benefiting all areas of the utility business. The Energy Policy Act in 2005 has significantly spurred the market for AMR technology innovation. The new innovation has also shown reduced cost and improved customer benefits, which helps the business case to move forward beyond the pilot stage.

Though a specific vendor has yet to be selected, DTE anticipates full service territory AMR deployment and installation over the next six years. The company plans to use a phased in approach and begin meter replacements in the areas with the highest density of meters.

4.5.5 Distributed Energy Resource Activities

DER can sometimes impact system planning, operations, and economics in ways not usually considered part of distribution planning or operations.

Presently, DTE is installing DG in the distribution system as a practical and economical solution to local reliability and power quality problems. Like a portable substation, DG can be used as an emergency, temporary, maintenance or permanent system. DTE reports that in its experience in using DG as a distribution planning tool, at most 3 percent of its circuits may have applications for DG. It serves as another tool that planning engineers can use to resolve loading problems.

These installations can help:

1. eliminate or defer expensive distribution system expansions;
2. improve distribution system reliability;
3. generate environmentally clean power and most importantly; and
4. provide high quality service to customers.

In 2003, DTE Energy Technologies, Inc signed a contract with NextEnergy to design and construct a state-of-the-art microgrid in the Power Pavilion on the NextEnergy site in Detroit. This microgrid demonstration project will be fueled by hydrogen, natural gas and sunlight. It will include the use of several emerging on-site energy technologies, including fuel cells, internal and external combustion engines, and solar cells. The microgrid will also include underground electrical and thermal distribution systems to provide electricity, heating and air conditioning to the NextEnergy facility. In addition, it will have the capability to serve the broader energy needs of the prospective buildings located within "Tech Town," a research and business technology park under development on the campus of Wayne State University in Detroit. The NextEnergy facility includes a 5,600-square-foot Power Pavilion, which will house the microgrid, a hydrogen

fueling infrastructure, office space, as well as a laboratory and product demonstration and exhibition facilities.

DTE is actively implementing DG in its distribution system to resolve both utility and customer problems. DTE has conducted DG technology demonstrations and installed DG as distribution solutions internal to the distribution circuit, at the substation and in an island mode to perform maintenance.

Throughout these implementations, DTE is:

1. partnering with customers on overloaded circuits, sharing the costs and benefits of DG through a premium power rate;
2. formally including DG analysis into the capital budget process as an alternative to traditional T&D solutions;
3. listing all known customer-owned DG and/or interruptible equipment; and
4. developing tools, such as the Distribution Engineering Workstation (DEW), to quantify the impacts of DG on the distribution system, particularly with regard to protection concerns.

DTE's operational strategy is to use DG to resolve distribution problems, not primarily as a generation option.

DTE has a fleet of seven DGs in use to support distribution ranging in size from 1 MW natural gas to 2 MW diesel fuel. They also have a 1.5 MW bi-fuel that can operate on blended natural gas and diesel. For 2006, six of the seven DG installations have been available to manage peak load.

In the longer term, DTE sees DG as a technology comparable to personal computers and cell phones. Just as these technologies fundamentally altered the computer and telecommunications industries, DG can help transform the traditional paradigm of the electric power system. DTE believes that DG will increasingly be a part of the utility landscape and play an expanding role in providing reliable, economical and high quality power.

Looking a bit further ahead, DTE envisions DER microgrids, or virtual utilities, providing continuous, economical, on-site power to multiple users and facilities in developments, complexes and premium power parks. The microgrid's appeal is:

1. fast siting;
2. comparatively low initial costs and high efficiency;
3. improved power quality, reliability and security; and
4. the capability of selling surplus energy.

4.6 Consumers Energy Modernization Activities

The following Consumers Energy initiatives support smart power grid technical categories and involve both full scale and pilot deployments.

4.6.1 SCADA/EMS Replacement

Consumers Energy is in the process of replacing its SCADA and Energy Management System which is driven by obsolescence, NERC Critical Infrastructure Protection (CIP) Standards, FERC Code of Conduct and the need for improved functionality.

The new system architecture will enable communication with multiple vendor applications and systems using industry accepted protocols. Some of the features include:

- CIM/XML Schema for model exchange;
- DNP 3.0 and DNP over IP protocols for communication with remote IEDs;
- ICCP and Secure ICCP for real time data;
- Multi Platform support Windows, Linux, and Unix;
- User Interface that supports interoperability with MS Windows applications;
- web based displays for viewing; and
- all databases, real time and historical, will be Open DataBase Compliant (ODBC).

System implementation is expected to begin in the 3rd quarter of 2006 and cutover is anticipated in the 2nd quarter of 2008.

4.6.2 Distribution Automation Intelligent Switching

Automatic load transfer switching schemes have been employed on utility distribution systems for some time. Recent advancements in wireless communication and smart switch capabilities have improved the functionality and expanded the potential application of smart “islands of automation.”

Consumers Energy has deployed four islands of automation on its low voltage distribution system using S&C’s IntelliTEAM technology. Each team involves two separate feeders and two to five intelligent switches, with one switch operated as the normal open point between the feeders. Using unlicensed spread-spectrum radio communication, the switches continually communicate with each other, monitoring the load and status of each switch. When a fault occurs on one of the feeders, all switches verify each others status and automatically restores all sections of the feeder up to the faulted section. The switches are also capable of determining the load serving capability of each section and will block transfer if the reconfigured system would result in an overload. This added intelligence results in automatic load transfer capabilities for all but a few days of the year where full redundancy does not exist between feeders.

One of the installed teams has been further enhanced by connecting the spread-spectrum communication into the SCADA system, making the real-time status and load information available anywhere in the company.

Investigation is underway with the latest generation of “islands of automation” technology that allows interconnection of up to eight substation and circuit combinations versus the present limit of only two feeders per team. The same features above apply with additional intelligence that allows more interruption scenarios and contingencies to be automatically restored. The new switches and controls also have the capability to change their internal settings so that system protection coordination can be maintained in the multiple system configurations.

4.6.3 Broadband Over Powerline

Commercial broadband over powerline has migrated from European to North American Markets over the past several years. Monitoring of trials, commercial deployments, regulatory issues and the potential for distribution applications, culminated in an agreement with The Shpigler Group to deploy a commercial pilot in the cities of Grand Ledge and St. Johns. Consumers Energy adopted the Landlord/Tenant business model used for other communication providers that attach to its system. The Shpigler Group owns and operates the BPL system and provides internet service under the name of Lighthouse Broadband.

BPL has the potential to enable distribution smart power grid applications by creating a communication network over the low voltage distribution system, providing connection to substations, critical line devices, customer meters and devices in the home. As part of the deployment, Consumers Energy intends a proof of concept pilot including substation equipment monitoring, distribution line equipment monitoring and meter reading.

Added grid intelligence is possible through the BPL Network Operating System that continually monitors the status of BPL field devices. Electric distribution outage and restoration status could potentially be inferred through monitoring BPL network/devices and making that information available to the utility to aid restoration activities. In cooperation with Lighthouse Broadband, the reliability and usefulness of outage information will be evaluated once the commercial roll out is significantly completed.

Lighthouse Broadband is testing new BPL technology and evaluating the performance. Initial tests were very positive and further production deployment is expected to commence once all testing and evaluations are completed. The determination to expand deployment beyond Grand Ledge and St. Johns will be once those systems are deployed and the distribution applications evaluated.

4.7 Indiana Michigan Power AMR

Indiana Michigan Power (I&M) employs AMR technology for about 30 percent of its meters in Michigan, primarily single phase residential services. Two AMR projects in Michigan were completed in 2005: (1) about 25,000 radio frequency (RF) meters are installed in the Benton

Harbor – St. Joseph – Stevensville area; and (2) approximately 14,000 power line carrier (PLC) meters are installed on nine circuits in other parts of the service territory. These are one way systems allowing the company to read meters.

The RF technology uses primarily General Electric meters with an Itron radio transmitting module. Meters are read using either hand held receivers or a laptop computer-driven receiver. The PLC system uses Hunt Technology meters and a receiver at the substation. These meters send data packets with a reading every 27 hours. Both systems can generate tamper and inversion detection flags.

In the next two years, I&M plans to install meters with three transmission modules in areas where the AMR technology is installed, to allow demand and time of use applications. I&M anticipates moving towards full deployment of AMR in the coming years.

Elsewhere on the AEP system, multiple automation pilot programs and investigations with outside suppliers are underway to determine the feasibility and future applications for smartgrid technology.

4.8 We Energies AMR

We Energies serves over 2.1 million customers in Wisconsin and the Upper Peninsula of Michigan, with over 1.1 million electric meters and one million gas meters. Deployment of AMR technology started with approximately 400,000 drive-by Itron modules on gas meters in Wisconsin beginning in 1992. AMR expansion began in 2002 using the Cellnet Technology, Inc., fixed network AMR system. AMR use has expanded to include over 650,000 gas and electric meters in the Wisconsin service areas and additional expansion is planned in coming years. Customer reaction to the AMR deployment has been very positive.

4.9 Great Lakes Energy Cooperative AMR (TWACS)⁹²

Great Lakes Energy Cooperative (GLE) serves approximately 120,000 meters. GLE has a fully implemented AMR program consisting of about 120,000 Two-Way Automatic Communication System (TWACS) AMR meters by DCSI. The TWACS system is a two-way power line carrier system that delivers data in two directions over the utility's power lines. A pilot project that was started in late 2004 has been fully implemented since the second quarter of 2006.

GLE presently obtains daily meter reads for its entire system. The system has the capability to obtain hourly meters reads which could be used to obtain demand data for load profiling. The system can determine if a meter is energized and therefore can detect power outages and is integrated with GLE's Outage Management System. Customer voltage reads can be obtained from the system as well.

⁹² For more information regarding the Two-Way Automatic Communication System (TWACS) system, go to <http://www.twacs.com/index.html>.

Remote disconnect/reconnect devices became available in 2006 and limited implementation was started in the second quarter 2006. Both the TWACS-DCSI AMR and the remote disconnect unit can detect metering tampering as well. MultiSpeak was used in the interface between GLE's Milsoft Outage Management system and the TWACS AMR system software.

4.10 Cloverland Cooperative AMR

Cloverland serves approximately 19,100 electric meters and began installing AMR technology in 2005. The co-op elected to proceed with full deployment of the DSCI (TWACS) fixed PLC system coupled with mixed communication components from the substations to the office. Cloverland's AMR system is designed to establish stable communications between the "smart" devices and the main office/hub. The co-op's system employs the flexibility to accommodate future development and additions to the system. Utilization of standard TCP/IP protocols allows full scalability with capable devices. The system uses a blade server for potential expansion requirements. Additional meters will not require system upgrades. Substation sites are modified to accommodate any future AMR or communications changes. Such modifications are done along with Spill-proof and Prevention Control (SPPC) substation upgrades, thereby minimizing the cost.

The expected benefits from this metering upgrade include the ability to leverage transportation costs, standardizing of consumption periods, near-instant low-cost ad-hoc meter reads, outage management, proactive system restoration, control of losses due to tampering, maintenance of correct phasing, future remote switching and voltage monitoring.

Currently, Cloverland has installed the new technology on 50 percent of the meters with 30 percent of the substations retrofitted and operational. Full deployment of the new system is expected to be completed in the third quarter of 2007.

4.11 Alger Delta Cooperative Electric Association

Alger Delta serves approximately 10,300 electric meters and began installing AMR technology in 2003. The co-op elected for the full deployment of the Hunt Technologies TS2⁹³ system.

The TS2 system is a fixed PLC system. Alger Delta has completed installation of approximately 9,500 out its 10,300 meters.

The Hunt TS2 system provides continuous endpoint communication that provides end-of-line voltage monitoring as well as outage and restoration detection and full two-way communications. Alger Delta currently uses the system for meter reading only.

Once the AMR is fully deployed the cooperative will implement outage and restoration management as part of its AMR program.

⁹³ For more information on the Hunt system, go to http://www.hunttechnologies.com/product_specs.asp#ts2.

4.12 Midwest Cooperative

Midwest Energy has a fully implemented TWACS AMR installation. Midwest has over 35,000 AMR meters installed on 30 substations. TWACS utilizes power line carrier technology to reach all of the company's meters, no matter how remote. TWACS provides daily usage, hourly profile usage, voltage reads, outage information, blink counts, demand side management, and remote disconnects with the speed and accuracy that Midwest members demand.

Midwest has previously used contract meter readers to get billing information. Manual meter reads incur problems with employee turn over, weather delays, and vehicle problems. AMR has eliminated these problems and gives Midwest customers accurate bills that virtually never need estimated.

Midwest has had great success in using the system to help customers with high bill complaints. Since it is possible to determine how much a member uses every day or even every hour, the customer can be shown exactly when and how they used the electricity and problems can be pinpointed.

Midwest uses the TWACS system for power quality issues several ways. During outage situations, the company can "ping"⁹⁴ meters to determine if the problem is occurring on the company or customer side of the meter. Blink counts are compiled daily, which helps to proactively trouble shoot blink problems or get accurate information when complaint calls are received. The system has even detected outages before the customers.

Midwest is also utilizing the system for demand side management. In the recent heat wave grid emergency, Midwest controlled over 5,000 water heater switches and dropped approximately 5 MW of the peak. This system is much more efficient for load management because it has a two way communication system. The company's old switches needed to be tested every few years for proper operation. With the TWACS system, repairs can be directed to switches that don't "answer." This permits more timely repairs and avoids inconvenience to members who have working switches.

Midwest has been working with Aisen, a division of Toyota, on a residential turbine and have used the load profile information from the TWACS meters to help determine what size turbine would be the most economical and useful for the customers.

Midwest utilizes a TWACS disconnect device on customers that have difficult to access meters or customers that are repeatedly disconnected for non-payment. This saves Midwest the expense of trips to customer's premises for disconnects.

⁹⁴ Packet Internet Groper (ping) is a computer utility that checks the quality of a link or verifies the connection of a machine to the Internet

4.13 Cherryland Electric Cooperative AMR (Implementation in Progress)

Cherryland Electric Cooperative (CEC) serves approximately 31,675 meters. To date CEC has installed approximately 8,000 TWACS meters on its system and is in the first year of a four year total system conversion. CEC is considering moving up the project to a three year time frame. The TWACS system is a two-way power line carrier system that delivers data in two directions over the utility's power lines. The current effort does include outage management and load control. Distribution automation will be a separate project once the system is fully deployed.

4.14 Michigan Public Service Commission Activities

4.14.1 Distributed Generation Interconnection Standards

The Michigan Customer Choice and Electricity Reliability Act (2000 PA 141) directed the Michigan Public Service Commission (MPSC or Commission)to establish standards, “for the interconnection of merchant plants with the transmission and distribution systems of electric utilities . . . consistent with generally accepted industry practices and guidelines . . . established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public” (MCL 460.10e).⁹⁵ The Commission developed rules to govern Electric Interconnection Standards (R 460.481–460.489).⁹⁶

Once the rules were fully developed, Michigan utilities filed interconnection procedures in concert with those rules.⁹⁷ These rules generally provide for the procedures Michigan's regulated electric distribution companies must employ when considering interconnection requests. They provide for the application process, basic technical criteria, filing fees, deadlines for the completion of the various steps in the process. The criteria, procedures, and timelines vary for five different categories based on the size of generators and required complexity of interconnections.

In reviewing technologies related to Michigan's 21st Century Energy Plan, it has been assumed that all interconnections with the utility grid must meet all technical and safety requirements. Further, it has been assumed that interconnections must always operate in a manner which assures the safety of all equipment interconnected with the utility grid and the health and safety of all persons who may come into contact with the grid and its interconnected equipment.

Despite interconnection standards currently in place, some applications for interconnections have experienced delays. In response to this, the Commission initiated a proceeding in late October

⁹⁵ [http://www.legislature.mi.gov/\(wgbxkq55zjnwtc2ym2nhu145\)/mileg.aspx?page=getObject&objectName=mcl-460-10e](http://www.legislature.mi.gov/(wgbxkq55zjnwtc2ym2nhu145)/mileg.aspx?page=getObject&objectName=mcl-460-10e).

⁹⁶ View online at: http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481.

⁹⁷ The utility procedures were approved in Cases Nos. U-14085 (for Northern States Power Company – Wisconsin, d/b/a.Xcel Energy), U-14091 (for Indiana Michigan Power Company, d/b/a American Electric Power), and U-14088 for all other utilities regulated by the Michigan PSC.

2006, Case No. U-15113 to: “(1) investigate the interconnection of independent power producers with a utility’s system, (2) identify any problems or deficiencies in the existing interconnection procedures, and (3) develop and implement remedies.” In addition, the Commission has directed utilities to file reports on all interconnections and pending applications completed pursuant to the approved procedures, including “whether any problems arose in the process.” The Commission also invited interested parties to file, by December 19, 2006, “information detailing interconnection problems they have experienced and any suggestions for changes to the interconnection procedures.” And, the Commission directed MPSC Staff to convene a public meeting on this subject on January 9, 2007, and file a report by January 31, 2007, “summarizing the issues identified and making recommendations for future action.” MPSC Staff believe this hearing process provides the appropriate venue for determining changes to the current utility interconnection procedures.

4.14.2 Net Metering Program (5-year)

Net metering is an accounting mechanism whereby retail electric utility customers who generate a portion or all of their own retail electricity needs are billed for generation (or energy) by their electric utility for only their net energy consumption during each billing period. Net energy consumption during a billing period is defined as the amount of energy delivered by the Utility and used by the customer, minus the amount of energy, if any, generated by the retail customer and delivered to the utility at the location of the eligible unit. In Michigan, a basic framework for regulated-utility net metering programs was developed through a consensus reached among Michigan utility companies and the MPSC Staff in 2004. That consensus agreement was subsequently approved, with modification by the Commission.⁹⁸ These are the basic provisions of the Michigan program: (It should be noted that these provision descriptions include the general outlines of the statewide net metering program. There are some variations in program implementation among Michigan electric utilities. The specific web page for a particular utility should be consulted in order to understand their program in detail).

1. **Total Program Size for Each Utility** – Each Utility will offer a net metering program with a maximum program limit of either 0.1 percent (one tenth of one percent) of the Utility's previous year's peak demand (measured in kW), or 100 kW, whichever is greater.
2. **Duration of the Program** – The net metering program shall be open for customer enrollments for a period of at least five years, and customers who enroll shall be eligible to continue their participation for a period of at least 10 years. Unless the program is changed by the Commission in the meantime, this gives customers until summer 2010 to complete their enrollment in the program. A participating customer may terminate their participation in a Utility's net metering program at any time for any reason.

⁹⁸ See <http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14346> for copies of all official documents associated with the net metering program, MPSC Case No. U-14346. The Consensus Agreement is document 0001 on that web page, and the Commission Order approving the Net Metering Program is document 0031.

3. **Qualifying Customers and Qualifying Technologies** – Net metering will be allowed for any full-requirements customers of Michigan electric utility companies regulated by the MPSC, on a first-come first served basis, who install qualifying renewable energy generators that are intended to serve their own energy needs. The maximum size generator that can be installed for net metering is less than 30 kW and systems must be sized not to exceed what is needed to serve the customer's self-service needs. Non-dispatchable generation systems (e.g., wind and solar) shall be sized not to exceed the customer's annual energy needs, measured in kilowatt-hours (kWh). Dispatchable systems shall be sized not to exceed the customer's capacity needs, measured in kilowatts.
4. **Net metering is open to all renewable energy source electric generating technologies** – Renewable energy sources are defined by Michigan Public Act 141 of 2000, Section 10g, to include "solar, wind, geothermal, biomass, including waste-to-energy and landfill gas, or hydroelectric." Biomass fueled systems will be allowed to blend up to 25 percent fossil-fuel, as needed to ensure safe, environmentally sound system operation.⁹⁹
5. **Applications, Application Fees, and Interconnection Standards** – Application fees, procedures, and requirements for interconnecting net metering customer generators will be those contained in the Commission's Electric Interconnection Standards Rules (R 460.481-460.489)¹⁰⁰ and the Utility's associated Commission-approved Generator Interconnection Requirements.¹⁰¹ Some utilities may require additional metering equipment for net metering customers¹⁰². Program details, including links to obtain guidelines, procedures, and application forms for each utility are included in the descriptions available on the MREP (Michigan Renewable Energy Program) Net Metering web pages¹⁰³

⁹⁹ Larger renewable energy systems can be installed and interconnected with the utility grid in Michigan, but they will not be eligible for net metering treatment. MREP has developed a web page to explain Interconnection and Rate Options for Non-Net-Metered Renewable Electric Generators in Michigan at http://www.michigan.gov/mpsc/0,1607,7-159-16377_43420---.00.html.

¹⁰⁰ MPSC Interconnection Standards Rules are available on the Internet at http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481&Dpt=&RngHigh=48702110.

¹⁰¹ Available online at, http://www.michigan.gov/mpsc/0,1607,7-159-16393_38274-126214--.00.html.

¹⁰² The Commission approved Interconnection Procedures for Michigan utilities in August 2004 Orders in Cases No. U-14085 (Northern State Power Company – Wisconsin, doing business as (d/b/a) Xcel Energy), see <http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14085>; Case No. U-14088 (Alpena Power Company, Consumers Energy company, The Detroit Edison Company, Edison Sault Electric Company, Upper Peninsula Power Company, Wisconsin Electric Power Company, d/b/a We Energies, Wisconsin Public Service Corporation and the Michigan Electric Cooperative Association), see <http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14088>; and Case No U-14091 (Indiana Michigan Power Company, d/b/a American Electric Power), see <http://efile.mpsc.cis.state.mi.us/cgi-bin/efile/viewcase.pl?casenum=14091>.

¹⁰³ http://www.michigan.gov/mpsc/0,1607,7-159-16393_38274---.00.html.

6. **Credits for Net Excess Generation** – In a typical net metering program, there are three categories of energy to consider: (1) energy delivered from the utility to the customer; (2) energy produced by the customer's renewable energy system and utilized on-site; and (3) energy produced by the customer's renewable energy system and delivered to the utility. In Michigan's program, net metered customers will be billed for the first type of energy just as any other similarly situated customer of their utility company. There will be no customer charges for the second type of energy, and no credits from the utility. For the third type of energy, customers will receive a credit equal to the retail power supply charges that the utility charges similarly situated customers. If, at the end of a billing period, the customer has produced and delivered to the utility any energy in excess of what the utility has delivered to the customer and the customer has used, that amount is termed net excess generation (NEG). Generally, Michigan utility companies will credit customers for NEG for an amount per kilowatt hour equal to the utility's retail power supply charges, and that dollar amount will be carried forward as a credit on the customer's next monthly bill. At the end of each year, however, the value of any remaining NEG credits will be claimed by the utility company and used to offset program costs, and the customer's NEG account will be reset to zero.
7. **Renewable Energy Certificates (RECs)**¹⁰⁴ – Customers will be eligible to receive renewable energy certificates for the energy they produce using their eligible self-service generators. Although the original Consensus Agreement included provisions for utilities to own RECs associated with net metered systems, the Commission deleted that portion of the Consensus Agreement when it approved the net metering program.
8. **Utility Reporting Requirements** – Each utility will report to MPSC Staff annually (each September) on: (a) the total number of participating customers in its net metering program; (b) five-digit zip code for each participating customer and starting month and year for each participating customer; (c) technology type and size in kW for each participating customer; (d) total NEG by technology type and cumulative total for each Utility's program (at the end of each 12-billingmonth cycle); and (e) any additional information the Utility believes is necessary in order to properly monitor and evaluate its net metering program. Information that would identify individual customers (such as name, address, account number, etc.) will remain confidential unless the customer gives written permission for such information to be shared.
9. **Program Monitoring and Evaluation** – The net metering program will be monitored and evaluated through the Michigan Renewable Energy Program process. Annual reports will be provided to the Commission and posted on the MREP website, with the first report expected in January 2007.

¹⁰⁴ For more information about RECs, including a directory of Certificate Marketers, see the U.S. Department of Energy GreenPower Network website, at <http://www.eere.energy.gov/greenpower/markets/certificates.shtml>.

The table below presents the four main focus areas associated with smart power grid technologies and the various characteristics which were investigated by the Alternative Technologies Workgroup. This is a preliminary guide that begins to provide evaluations of smart power grid technology options, issues, and respective impacts – both negative and positive – on the state’s electric utility infrastructure. This is not a comprehensive listing nor includes all of the initiatives currently underway.

Table 1: Characterization of Smart Power Grid (SPG) Technologies

| Technology Category | Smart Power Grid Application Description | Technology Options | Implementation Benefits | Barriers To Adoption | Commercial Readiness |
|---|--|---|--|--|--|
| | Grid-wide, Two-Way Data Acquisition Infrastructure | Open Standards Architecture; Smart Meters; Commercial Communication Infrastructures; Proprietary Communication Infrastructures; Consumer IP portal (gateway) ² | Real-time modeling; Self-healing grid; Improved Grid maintenance; Incremental long-term grid reliability improvements. | Cost. Smart Meter adoption is a prerequisite, to facilitate other SPG benefits. Lack of common standards & architecture; Full benefits likely to appear incrementally over time. Limited deployment of some infrastructures. | Smart Meters commercially available; Architecture ready but standards not yet adopted; Common information acquisition model not ready. Limited band width on some existing infrastructures. |
| Architecture and Communication Standards³ | EPACT 2005 – Created successor to NERC (ERO) | NERC (ERO) standards development; Enhanced security operations and system hardening. | Efficiency; Security; Reliability; Economics. | Regarding communication infrastructure, “one size does not fit all.” Bandwidth, access and security requirements will vary, depending on the applications being considered. | Some segments of technology have settled on “defacto” communication standards. Much work remains, to arrive at open standards for communication and application software. |
| | Demand-Side Management | Smart Meters; Grid management infrastructure; Appliance monitoring and control. | Improved load management; tariff benefits; cost savings. | Cost; Lack of unified open-standards control and communications architecture; Customer value assessment. | Meters commercially available. Some small scale control architectures available (e.g., through MultiSpeak Initiative). Various communication and control architectures not fully integrated. |

| Technology Category | Smart Power Grid Application Description | Technology Options | Implementation Benefits | Barriers To Adoption | Commercial Readiness |
|---------------------------------------|---|---|--|---|--|
| Monitoring and Load Management | Distribution Monitoring and Control | Smart Meters; Islands of Automation; Line Equip Electronic Controls; Line sensors | Outage Management & Response; Load Characterization and Grid Mgt; Self Healing Networks. | Cost; Lack of unified open standards for control and communication architecture; Limited looped distribution systems – i.e., majority are radial. | Meters commercially available. Some small scale control architectures available (MultiSpeak Initiative). Various communication and control architectures not fully integrated. |
| | EPACT 2005 Implementation increased facility investment advanced facility technology deployment | Investment in new & expanded R/W; Advanced conductor technology; superconducting technology; automated dist. ckt. reconfiguration | Increased grid capacity; Improved efficiency; Increased reliability; | Jurisdictional conflicts; R/W acquisition delays; | Improved conductor designs are currently available; superconductivity equip. not ready for deployment |
| | Enhanced DER Management; | Increased deployment of DER (CHP, Wind power, Fuel cells, solar cells); MicroGrid technology development; Ancillary service market improvements | Improved grid control, efficiency & grid stability; | Cost; Siting difficulties; Costs of load following for wind DER; lack of unified grid control architecture; Lack of integrated DER control; | Wind power commercially available; Fuel cell prototype stage; |
| Advanced Grid Operations | Voltage Support | Planned siting for DER; | Improved grid control, efficiency & stability; | Limited control over siting of new resources; | |
| | Reactive Support | STATCOM; DSTATCOM; SuperVAR; strategic siting for DER; Local/Distributed VAR Control | Voltage Sag & Flicker support; Real-time grid management | Cost; Application specific; Increased grid management complexity; Market for reactive immature; | STATCOM & DSTATCOM are commercially available; SuperVAR is in prototype; Limited RTO control and siting for reactive sources; |
| | Load-following Support | Other designated DER facilities; | Improved grid reliability; | Cost; Increased use of DER without load following; | |
| | Power Quality Support | Advanced harmonic filtering; | Improved power quality for sensitive loads; Improved grid efficiency; | Increased use of harmonic-producing technologies; | |

| Technology Category | Smart Power Grid Application Description | Technology Options | Implementation Benefits | Barriers To Adoption | Commercial Readiness |
|--------------------------------|--|--|---|--|---|
| | Power Storage | Batteries; Flywheel | Improved grid efficiency; | Cost; Application specific; | |
| Modeling and Simulation | Grid Management; standardized data structures; improved modeling of DER; improved load forecasting tools; value-based reliability tools; improved generation dispatch models; improved market modeling tools | IT Systems and Application Software Development; | Integration of complex analytical & real-time data to control and maximize grid utilization and reliability; potential software “bugs”; | Costs; Proprietary and incompatible software tools, Lack of available monitoring | “Real-time” tools exist and are used at the Transmission and Sub-Transmission levels. Distribution Tools exist. Modeling and simulation based on historical and predicted loads; dynamic islands of automation becoming more available. |